Preliminary
Best Available Control Technology
Determination
for
Control of Nitrogen Oxides
for
M.R. Young Station
Units 1 and 2

June 2008

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ND Department of Health
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Table of Contents

I. Introduction

Minnkota Power Cooperative operates the M.R. Young Station near Center, North Dakota. Unit 1 of the station is owned by Minnkota and has a gross rating of approximately 250 MWe. Existing air pollution controls consist of a cold side electrostatic precipitator. Unit 2, which is owned by Square Butte Electric Cooperative, has a rating of approximately 477 MWe gross. Existing air pollution control equipment consists of a cold-side electrostatic precipitator and a lime/flyash wet scrubber for sulfur dioxide control. Unit 1 went online in 1970 while Unit 2 began operations in 1977. Both units are fired on lignite which is obtained from BNI Coal Ltd.'s Center Mine which is adjacent to the station.

On July 27, 2006 a Consent Decree was entered by the United States District Court for the District of North Dakota for Civil Action No. 1:06-CV-034, United States of America and the State of North Dakota versus Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative. The Consent Decree resolved alleged violations of the North Dakota Air Pollution Control rules (NDAC 33-15) including the Prevention of Significant Deterioration Rules (NDAC 33-15-15). Section V, Paragraph 65, of the Consent Decree required Minnkota Power Cooperative and Square Butte Power Cooperative (hereafter Minnkota) to submit to the Department for review and approval a nitrogen oxides (NO_x) top-down Best Available Control Technology Analysis (BACT) for the two existing units at the M.R. Young Station. The Consent Decree requires Minnkota to evaluate various technologies including selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), over-fire air (OFA) and rich reagent injection (RRI). Minnkota is also required to submit any additional information requested by the Department or the U.S. Environmental Protection Agency (hereafter EPA) which is pertinent to the BACT determination. The BACT analysis must address both a normal operating scenario and a startup scenario. The BACT analysis must specify the technology to be installed and recommend an emission rate, on 30-day rolling average basis, that is BACT for each of the units and for each scenario evaluated.

On October 9, 2006, the Department received the required BACT analyses. A review of the analyses indicates Minnkota has included the items required by the Consent Decree.

Since the original analysis, the Department has received comments on the BART analysis from the U.S. Environmental Protection (and their consultant Roger Christman of Eastern Research Group, Inc.), Minnkota's responses to the Department's and EPA comments, and information from Basin Electric Power Cooperative (through their consultant Sargent and Lundy, LLC). The following documents are contained in Appendix A.

1. Minnkota letter providing reference material from presentation on BART; March 14, 2006; attachments include:

    a) SCR Catalyst Performance in Flue Gases Derived From Subbituminous and Lignite Coals; Benson, Steven A, et al.

    b) The Proceeding of the 27th International Technical Conference on Coal Utilization & Fuel Systems; Volume II of II.

    c) Twenty-five Years of SCR Evolution: Implications for US Application and Operation; Cichanowicz, J.E.; Muzio, L.J.

    d) Utility Experience with SCR in Germany; Hartenstein, Hans-Ulrich; et al.

    e) The Selective Catalytic Reduction of NO_x Emissions from Utility Boilers; Mukherjee, Arun B.

    f) SCR Catalyst Design Issues and Operating Experience: Coals with High Arsenic Concentrations and Coals from the Powder River Basin; Rigby, Katuna; et al.

    g) Optimizing SCR Catalyst Design and Performance for Coal-fired Boilers; Pritchard, Scot; et al.

2. Minnkota's Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1; October 2006.

3. Square Butte Power Cooperative's Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2; October 2006.

4. ERG Memorandum to Hans Buenning of EPA Region 8, et. al. regarding review and critique of NO_x BACT Analysis for M.R. Young Station; January 8, 2007.

5. EPA Transmittal of Non-SCR concerns and additional information required for Minnkota BACT analysis study; January 26, 2007.

6. Department letter to Minnkota providing comments on Best Available Control Technology Analyses; February 1, 2007.

7. Minnkota Response to ERG review; March 19, 2007.

8. Minnkota Response to Department's February 1, 2007 Comments; April 23, 2007.

9. "Summary of Responses to EPA/DOH Questions on Minnkota Power's NO_x BACT Analysis for Milton R. Young Units 1 & 2" Power Point Presentation Slides by EERC, Burns and McDonnell, and Minnkota Power Cooperative; May 23, 2007.

10. "Application of SCR Technology to North Dakota Lignite Fuels", Power Point Presentation slides by Sargent and Lundy, LLC; May 2007.

11. Minnkota letter with report titled "Appropriateness of Conducting Pilot Testing of Selective Catalytic Reduction (SCR) Technology at Milton R. Young Station Units 1 and 2, for use in a NO_x BACT Analyses"; August 16, 2007.

12. EPA letter in response to Minnkota's March 19, 2007 and April 23, 2007 letters; October 4, 2007.

13. Minnkota letter in response to EPA's October 4, 2007 letter; November 9, 2007.

14. Minnkota letter regarding BART conference; November 29, 2007.

15. Additional information and Discussion of Vendor Responses on SCR Technical Feasibility; North Dakota's NO_x BACT Determination for Milton R. Young Station Units 1 and 2; May 8, 2008.

The information submitted by Minnkota, and their consultants Burns and McDonnell and the Energy and Environmental Research Center (EERC), suggests that SCR technology is not technically feasible for the M.R. Young Station. EPA, and their consultant ERG, Inc., suggest that SCR technology is technically feasible. Information from Sargent and Lundy indicates that not enough information is available to determine whether SCR technology can be successfully adapted to units burning North Dakota lignite.

II. **Summary of Decision**

The primary issue facing the Department in making its BACT determination is whether SCR technology is technically feasible for North Dakota lignite-fired cyclone boilers. The information submitted by Minnkota, and their consultants Burns and McDonnell and the Energy and Environmental Research Center (EERC), suggests that SCR technology is not technically feasible for the M.R. Young Station. EPA, and their consultant ERG, Inc., suggest that SCR technology is technically feasible. Information from Sargent and Lundy indicates that not enough information is available to determine whether SCR technology can be successfully adapted to units burning North Dakota lignite.

The Department has carefully examined all submissions to determine the best available control technology to control NO_x emissions from Minnkota Units 1 and 2, and determines that SCR is not technically feasible for North Dakota lignite-fired cyclone boilers. The July 27, 2006, Consent Decree provides that the NO_x Top-Down BACT analysis will be carried out in accordance with the provisions of

Chapter B of EPA's "New Source Review Workshop Manual—Prevention of Significant Deterioration and Nonattainment Area Permitting." In Step 2 of the Top-Down analysis, the technical feasibility of the control options identified in step 1 is evaluated. The fundamental question for this BACT Determination is whether SCR is an available technology for North Dakota lignite-fired cyclone boilers such as Minnkota Units 1 and 2.

EPA states that "the Minnkota BACT analysis for SCR should begin with the presumption that SCR is technically feasible, since the technology has been widely demonstrated on utility boilers … based on the 'technology transfer' discussion in the NSR Workshop Manual … and the fact that hundreds of SCR systems have been successfully installed on utility boilers worldwide." These technological fixes are unproven to transfer to this boiler/fuel type, and the use of SCR to control NO_x has only been demonstrated for utility boilers that have substantially dissimilar gas streams.

The NSR Workshop Manual provides that technical judgment of the review authority must be exercised in determining whether a control alternative is applicable to the source type under consideration. The manual states that generally, "**a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison of the gas stream characteristics of the source types to which the technology had been applied previously.**"

SCR has not been demonstrated to be technically feasible for North Dakota lignite-fired cyclone boilers (i.e., SCR hasn't been applied to this source type). In addition, the lignite fired boiler the gas stream has unique qualities different than gas streams of other coal-fired boilers that cause unique catalyst deposition, erosion, poisoning, blinding (or fouling or surface masking) and plugging that are unresolvable barriers in the ability of known SCR technologies to control NO_x stack emissions. This makes SCR an ineffective NO_x control system in this case.

By asserting that unproven technological fixes such as aggressive on-line cleaning and/or frequent extended forced outages to replace the catalyst will make SCR available in this case, EPA attempts to thereby convert the issue to one of cost evaluation under step 4 of the BACT analysis. But the available evidence indicates that the gas stream from high sodium lignite causes catalyst plugging and blinding, which is not solved by the proposed technological fixes. EPA's contention that technological solutions will be developed for effective SCR NO_x control is speculative.

EPA asserts that there are many tools in the toolbox to address SCR technical issues, including screens, soot blowing, and a high catalyst pitch to accommodate a catalyst replacement of about once a year. Again, such proposed technological fixes are unproven. The Department finds that catalyst replacement would be required more frequently than normal industry experience, and is unreasonable.

The NSR Manual notes that a control technology "**is considered available if it has reached the licensing and commercial stage of development. A source would not be required to experience extended time delays or research penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review.**" SCR has not reached this stage for North Dakota lignite-fired cyclone boilers, and because of the difference in the gas stream, the Department concludes that Minnkota need not experience extended trials to learn how to apply the technology on such a dissimilar source type. EPA's contention that technological solutions will be developed is speculative.

The pilot testing at the Coyote Station did not provide much useful data, and in hindsight, was ill-designed for a unit combusting North Dakota lignite. Yet, the test did indicate a significant difference between lignite and subbituminous coal, describing blinding and plugging (deactivation) at the Coyote Station as extremely rapid and severe as compared to testing at the Columbia and Baldwin Stations. Because of the lack of deactivation data from the pilot test at the Coyote Station, it is risky and difficult to design an SCR system; the Department concludes that design of an SCR system for North Dakota lignite would be different from a unit burning subbituminous coal. In sum, additional research and testing on the effects of the flue gas constituents are required to design an SCR system for North Dakota lignite.

Besides catalyst deactivation, it is likely that a high-dust SCR would experience plugging problems (deposition on the catalyst surface) due primarily to the carry over of "popcorn ash" from the boiler. The popcorn ash is generated during cleaning actions within the boiler which are quite frequent due to the characteristics of North Dakota lignite. The advances made in the last few years for controlling popcorn ash are not shown to be applicable to a cyclone boiler burning North Dakota lignite. Extensive engineering analyses, and likely pilot scale testing, will be necessary to determine if these advances can be applied at the M.R. Young Station. The requirement for pilot scale testing or additional research would eliminate SCR from further consideration pursuant to the NSR Manual.

Additionally, SCR is technically infeasible due to erosion of the catalyst. Because of the high ash content and frequent cleaning cycles due to the deposition characteristics of North Dakota lignite ash, erosion may be more of a concern than with a bituminous or subbituminous coal-fired unit. Although pilot scale testing is now underway at the Sandow Plant in Texas—which burns Texas lignite—its results are not yet available. Additional design work and pilot testing is required before a conclusion can be made that SCR can be successfully applied as NO_x control for North Dakota lignite-fired units.

While EPA's expert, Roger Christman, supports EPA's contention that the wealth of experience in the utility industry applying SCR to solid fuel utility boilers creates a presumption of technical feasibility, the presumption does not take into account the differences in the gas streams, and the conclusion is not consistent with the experience of the most qualified experts. The BACT assessment for Minnkota was prepared by Burns and McDonnell, which has considerable experience with SCR systems, and the EERC, which has extensive experience with North Dakota lignite. Sargeant and Lundy, LLC (S&L), another consulting firm, also made a presentation to the Department on the application of SCR technology to North Dakota lignite fuels. S&L, which is entirely dedicated to the electric power industry, indicated it had designed 46% of the SCR systems in the United States. Of the SCR systems, 39 were for coal-fired units with 10 designed for Powder River Basin subbituminous coal. While S&L provided possible solutions for deactivation of the catalyst, they indicated there was no known solution for deactivation due to soluble sodium compounds generated by the combustion of North Dakota lignite. S&L speculated that more catalyst and a larger reactor may be a possible solutions; however, how much more catalyst or how much larger the reactor would have to be to solve the problem was unknown. In sum, S&L concluded that there are attributes of North Dakota lignite in an SCR environment that are not well understood today and need more investigation to predict its performance. S&L recommendations included a parametric pilot test program.

Although the Department would have preferred a more complete record that included more extensive pilot testing of SCR using North Dakota lignite in cyclone boilers, the Department must make its decision on the available information, which indicates that pilot testing and redesign of the catalyst are necessary before SCR can be shown to be a technically feasible technology in this case.

The Department has determined that BACT for both units at the M.R. Young Station is represented by advanced separated over fire air (ASOFA) and selective noncatalytic reduction (SNCR).

III. **Methodology**

The North Dakota Air Pollution Control Rules, Section 33-15-15-01.2 defines Best Available Control Technology as:

> An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Department, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The steps for conducting a BACT analysis using the "top down" approach are as follows:

Step 1: **Identify All Control Technologies.**

- List is comprehensive.

Step 2: **Eliminate Technically Infeasible Options.**

- A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

EPA's New Source Review Workshop Manual[1] (hereafter NSR Manual) provides guidance for determining whether a control option is technically infeasible. Two concepts are important in making this determination, "availability" and "applicability". A technology is considered "available" if it can be obtained through commercial channels or is otherwise available within the common sense meaning of the word. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is considered technically feasible.

Regarding "availability" the NSR Manual[1] states:

> **"A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in a pilot scale testing stages of development would not be considered available for BACT review."**

With respect to "applicability" the NSR Manual[1] states:

> **"Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon**

to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.

In practice, decisions about technical feasibility are within the purview of the review authority. Further, a presumption of technical feasibility may be made by the review authority based solely on technology transfer. For example, in the case of add-on controls, decisions of this type would be made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is to be transferred. Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary."

With regard to the types of control options to be considered, the NSR Manual[1] states: **"Each new or modified emission unit (or logical grouping of new or modified emission unit(s))** subject to PSD is required to undergo BACT review. BACT decisions should be made on the information presented in the BACT analysis, including the degree to which effective control alternatives were identified and evaluated. Potentially applicable control alternatives can be categorized in three ways.

- *Inherently Lower-Emitting Processes/Practices*, including the use of materials and production processes and work practices that prevent emissions and result in lower "production-specific" emissions; and

- *Add-on Controls*, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.

- *Combinations of Inherently Lower Emitting Processes and Add-on Controls*. For example, the application of combustion and post-combustion controls to reduce NO_x emissions at a gas-fired turbine.

The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review."

Step 3: **Rank Remaining Control Technologies By Control Effectiveness**

This includes:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year);
- expected emission reduction (tons per year);
- energy impacts (Btu, KW-hr);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness and incremental cost effectiveness).

Step 4: **Evaluate Most Effective Controls and Document Results**

- Case-by-case consideration of energy, environmental, and economic impacts.
- If most effective options is not selected as BACT, evaluate next most effective control option.

Step 5: **Select BACT**

- Most effective option not rejected is BACT and establish emission limit or work practice standard.

IV. BACT Determination

Both units at the M.R. Young Station are cyclone fired units which burn North Dakota (Fort Union) lignite from the Center Mine. Since both units employ cyclone firing and are similar in many other respects, the following discussion is applicable to both units.

A. Step 1: Identify All Control Technologies

Minnkota identified the following technologies or control methods:

Combustion Improvements
Fuel Switching/Blending/Cleaning
*High Dust Selective Catalytic Reduction (SCR)
*Low Dust SCR

*Tail-gas SCR
*Electro-Catalytic Oxidation (ECO)
*Selective Noncatalytic Reduction (SNCR) including Rich Reagent Injection (RRI) and Hydrocarbon Enhanced SNCR (HE-SNCR)
*Flue Gas Recirculation
*Separated Overfire Air (SOFA) including Boosted SOFA Rotating Opposed Fired Air (ROFA™) and Advanced Separated Overfire Air (ASOFA)
*Fuel Reburn
Oxygen Enhanced Combustion
Water/Steam Injection

*Could be applied in combination with other technologies or methods.

B. **Step 2: Eliminate Technically Infeasible Options**

1. **Fuel Switching/Blending**

The Milton R. Young Station was designed and has operated for over 35 years as a mine mouth power plant. There is no railroad access to the plant. The Department believes the nearest rail line is approximately 10 miles away. Switching to Powder River Basin (PRB) subbituminous coal would not lower NO_x emissions. The Big Stone Power Plant in South Dakota is a cyclone boiler which burns PRB subbituminous coal. A review of EPA's Acid Rain Database indicated a 2005 annual average NO_x emission rate of 0.83 lb/10^6 Btu. This is compared to the baseline emission rate for M.R. Young Unit 1 of 0.849 lb/10^6 Btu and 0.786 lb/10^6 Btu for Unit 2. Switching to PRB subbituminous coal would have little effect on NO_x emissions and may actually increase emissions. Since combusting PRB coal would have little effect on emissions, this option, although technically feasible, is not considered further.

In August, 2007, the United States Court of Appeals for the Seventh Circuit issued its decision in the Prairie

State Generating case (Sierra Club, et al. v. U.S. Environmental Protection Agency and Prairie State Generating Company, LLC at 499 F. 3d 653,654; 7th Cir. 2007). The Department interprets this decision to indicate that fuel switching is not required for a mine mouth power plant such as M.R. Young Station. Therefore, Minnkota is not required to consider switching coal or bringing in other types of coal for blending to address the characteristics of Center lignite that would affect any of the control technologies.

2. **Selective Catalytic Reduction (SCR)**

a. **High Dust SCR**

<u>Technical Review</u>

The SCR process is based on the chemical reduction of the NO_x molecule using a metal based catalyst with activated sites to increase the rate of the reduction reaction. A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reagent reacts selectively with the flue gas NO_x within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_x molecule into molecular nitrogen and water vapor.[2]

In order for SCR to be technically feasible, it must be both "available" and "applicable". SCR has been applied to the many different types of coal throughout the world. Based on its widespread usage, it would initially appear to be available for use at the M.R. Young Station.

As stated previously, the NSR Manual[1] states that decisions regarding technical feasibility are made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is being transferred. Unless significant differences between the source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary. In order to compare the flue gas at the M.R. Young Station to gas streams where SCR has been successfully applied, a comparison of the different fuel (coal) characteristics is helpful.

EPA's Air Pollution Control Cost Manual[2] states: **"Certain fuel constituents which are released during combustion act as catalyst poisons. Catalyst poisons include calcium oxide and magnesium oxide, potassium, sodium, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them irreversibly. Catalyst poisoning represents the main cause of catalyst deactivation.**

Ammonia-sulfur salts, fly ash, and other particulate matter in the flue gas cause blinding, plugging or fouling of the catalyst. The particulate matter deposits on the surface and in the active pore sites of the catalyst. This results in a decrease of the number of sites available for NO_x reduction and an increase in flue gas pressure loss across the catalyst.

Impingement of particulate matter and high interstitial gas velocities erode the catalyst material. Catalysts with hardened leading edges or increased structural strength are less susceptible to erosion. Increasing catalyst strength through

hardening, however, reduces the number of active pore sites."

Minnkota has indicated that the most significant problem for the successful operation of SCR catalysts on units that fire North Dakota lignite is the formation of low temperature sodium-calcium-magnesium sulfates and phosphates. Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. The sodium content of the Center Mine lignite ash historically averages 4.4% and can more than double this value for some of the lignite produced. Powder River Basin (PRB) coal from Wyoming typically averages around 1.5% sodium[3].

A review was conducted to independently compare the constituents of fuels for which SCR has been successfully applied to that of North Dakota lignite. Data was obtained from the U.S. Geological Survey's U.S. Coal Quality Database[3]. The results are shown in Table 1.

Table 1
COAL CHARACTERISTICS
COMPARISON

	Center Lignite[b] (Historical)	Center Lignite[b] (Future)	Texas Lignite[a]	Wyoming PRB[a]	PA Bituminous[a]
Avg. Heat Value (10^6 Btu/ton)	13.2	13.4	15.2	17.0[c]	25.5
Avg. Ash Content	9.6	7.8	12.6	5.0[c]	13.0
Avg. Na_20 (% of Ash) Std. Deviation	4.4 2.2	5.6 3.4	0.5 0.6	1.6 1.3	0.3 0.2
Avg. Ca0 (% of Ash) Std. Deviation	13.1 3.2	17.0 5.3	13.2 5.2	17.3 7.4	1.7 1.6
Avg. Mg0 (% of Ash) Std. Deviation	4.0 0.8	5.1 1.2	2.3 1.1	3.8 2.1	0.6 0.3
Avg. K_20 (% of Ash) Std. Deviation	1.3 0.4	1.0 0.7	0.5 0.3	0.5 0.4	1.9 0.8
Na_20+Ca0+Mg0+K_20 (% of Ash)	22.9	28.7	16.5	23.2	4.5

a Heating values, ash content and ash constituents from the USGS National Coal Database except as noted.
b From Minnkota's April 23, 2007 submittal.
c From University of Wyoming.

In order to properly compare flue gas conditions, an estimate of the total emission rate of the deactivation (fouling and poisoning) constituents can be made. Although the catalyst deactivation rate may not be directly proportional to the emission rates of the various constituents, it does provide a means of comparison of the flue gas characteristics.

AP-42, <u>Compilation of Air Pollutant Emission Factors</u>[4], lists the following particulate matter emission factors as shown in Table 2.

Table 2 AP-42 EMISSION FACTORS		
Combustion Unit Type	**Fuel**	**Emission Factor**
Cyclone	Lignite	6.7A
Cyclone	Bit./Subbit.	2.0A
Wall/Tangential	Bit./Subbit.	10.0A
Wall	Lignite	6.5A
Tangential	Lignite	5.1A

A = Ash content of the coal (%)

In its analysis, Minnkota indicated that approximately 45 - 50% of the ash in the lignite combusted at the M.R. Young Station is emitted from the boiler. The Department reviewed the ESP performance test for Unit 2 to verify this assertion. The results of the review indicated an average emission rate of 46.9% of the ash in the lignite which yields an emission factor of 9.4A (lb/ton). The results are shown in Appendix B. Minnkota's assertion appears valid.

To assess whether the flue gas characteristics at the M.R. Young Station are different from characteristics at other generating stations where SCR has been successfully applied, the emission rate, or loading, of the various deactivation constituents and the chemical form (organic or inorganic) of these constituents must be evaluated. Using the coal characteristics data from Table 1, the emission factors from Table 2, and the results of the review of Minnkota's emission factor, the emission rate of the deactivation constituents were calculated. Emphasis was given to the sodium oxide (Na_2O) emission rate because North Dakota lignite generally contains more Na_2O than bituminous or subbituminous coal. Since cyclone boilers firing North Dakota lignite partition the ash, the sodium is concentrated in the ash leaving the boiler. The results of the following calculation will underestimate the amount of sodium in the flue gas for a cyclone boiler firing North Dakota lignite; however, it does provide a conservative comparison. The results of the calculation are provided in Table 3:

Table 3
HISTORICAL COAL EMISSION RATE COMPARISON

	CENTER LIGNITE [a]	TEXAS LIGNITE [b]	WYOMING PRB SUBBITUMINOUS [b]	PA BITUMINOUS [b]
Na_2O (% of Ash)	4.4	0.5	1.6	0.3
CaO (% of Ash)	13.2	13.2	17.3	1.7
MgO (% of ash)	4.0	2.3	3.8	0.6
K_2O (% of Ash)	1.3	0.5	0.5	1.9
$Na_2O+CaO+MgO+K_2O$ (% of Ash)	22.9	16.5	23.2	4.5
Ash Content	9.6	12.6	5.0	13.0
Heat Value (10^6 Btu/ton)	13.2	15.2	17.0	25.5
PM Emission Factor (lb/ton/1% Ash) [c,d]				
Cyclone Boiler	9.4	6.7	2.0	2.0
Wall/Tangentially-fired Boiler (Pulverized)	5.8	5.8	10.0	10.0
PM Emissions (lb/10^6 Btu)				
Cyclone Boiler	6.84	5.55	0.59	1.02
Wall/Tangentially-fired Boiler (Pulverized)	4.22	4.81	2.94	5.10
Na_2O Cyclone Boiler Emissions				
lb/ton	3.97	0.42	0.16	0.08
lb/10^6 Btu	0.3008	0.0278	0.0094	0.0031
lb/dscf	3.0507E-05	2.8164E-06	9.6235E-07	3.1276E-07
lb/wscf	2.5172E-05	2.3238E-06	8.8456E-07	2.8748E-07
$Na_2O+CaO+MgO+K_2O$ Cyclone Boiler Emissions				
lb/ton	20.66	13.93	2.32	1.17
lb/10^6 Btu	1.5655	0.92	0.14	0.05
lb/dscf	1.5878E-04	9.2941E-05	1.3954E-05	4.6914E-06
lb/wscf	1.3101E-04	7.6686E-05	1.2826E-05	4.3123E-06

Table 3 Continued

	CENTER LIGNITE [a]	TEXAS LIGNITE [b]	WYOMING PRB SUBBITUMINOUS [b]	PA BITUMINOUS [b]
Ratio of ND Lignite Cyclone Emissions to Other Cyclones				
Na_2O				
lb/ton		9.4	24.8	50.9
lb/10^6 Btu		10.8	32.0	98.3
lb/dscf		10.8	31.7	97.5
lb/wscf		10.8	28.5	87.6
$Na_2O+CaO+MgO+K_2O$				
lb/ton		1.5	8.9	17.7
lb/10^6 Btu		1.7	11.5	34.1
lb/dscf		1.7	11.4	33.8
lb/wscf		1.7	10.2	30.4
Comparison of ND Lignite Cyclone to Pulverized Units				
Na_2O Emissions				
lb/ton	3.97	0.37	0.80	0.39
lb/10^6 Btu	0.3008	0.0240	0.0471	0.0153
lb/dscf	3.0507E-05	2.4381E-06	4.8117E-06	1.5638E-06
lb/wscf	2.5172E-05	2.0117E-06	4.4228E-06	1.4374E-06
$Na_2O+CaO+MgO+K_2O$ Emissions				
lb/ton	20.66	12.06	11.60	5.85
lb/10^6 Btu	1.5655	0.7933	0.6824	0.2294
lb/dscf	1.5878E-04	8.0457E-05	6.9770E-05	2.3457E-05
lb/wscf	1.3101E-04	6.6385E-05	6.41309E-05	2.15613E-05
Ratio of ND Lignite Cyclone Emissions to Pulverized Units				
Na_2O				
lb/ton		10.9	5.0	10.2
lb/10^6 Btu		12.5	6.4	19.7
lb/dscf		12.5	6.3	19.5
lb/wscf		12.5	5.7	17.5

Table 3 Continued

	CENTER LIGNITE [a]	TEXAS LIGNITE [b]	WYOMING PRB SUBBITUMINOUS [b]	PA BITUMINOUS [b]
$Na_2O+CaO+MgO+K_2O$				
lb/ton		1.7	1.8	3.5
lb/10^6 Btu		2.0	2.3	6.8
lb/dscf		2.0	2.3	6.8
lb/wscf		2.0	2.0	6.1

[a] Information from Minnkota's April 16, 2007 submittal.

[b] Data from the USGS National Coal Database and University of Wyoming.

[c] From AP-42, Compilation of Air Pollutant Emission Factors except for Minnkota which is based on actual stack testing.

[d] Emission factor for tangentially and wall-fired units burning lignite is the average of the AP-42 emission factors.

Minnkota has also provided data on core samples of lignite in future mining areas. Using this data, the calculated constituent emission rates area are provided in Table 4.

Table 4

FUTURE COAL EMISSION RATE COMPARISON

	CENTER LIGNITE [a]	**TEXAS LIGNITE** [b]	**WYOMING PRB SUBBITUMINOUS** [b]	**PA BITUMINOUS** [b]
Na_2O (% of Ash)	5.6	0.5	1.6	0.3
CaO (% of Ash)	17.0	13.2	17.3	1.7
MgO (% of ash)	5.1	2.3	3.8	0.6
K_2O (% of Ash)	1.0	0.5	0.5	1.9
$Na_2O+CaO+MgO+K_2O$ (% of Ash)	28.7	16.5	23.2	4.5
Ash Content	7.8	12.6	5.0	13.0
Heat Value (10^6 Btu/ton)	13.4	15.2	17.0	25.5
PM Emission Factor (lb/ton/1% Ash) [c,d]				
Cyclone Boiler	9.4	6.7	2.0	2.0
Wall/Tangentially-fired Boiler (Pulverized)	5.8	5.8	10.0	10.0
PM Emissions (lb/10^6 Btu)				
Cyclone Boiler	5.47	5.55	0.59	1.02
Wall/Tangentially-fired Boiler (Pulverized)	3.38	4.81	2.94	5.10
Na_2O Cyclone Boiler Emissions				
lb/ton	4.11	0.42	0.16	0.08
lb/10^6 Btu	0.3064	0.0278	0.0094	0.0031
lb/dscf	3.1076E-05	2.8164E-06	9.6235E-07	3.1276E-07
lb/wscf	2.5641E-05	2.3238E-06	8.8456E-07	2.8748E-07

Table 4 Continued

	CENTER LIGNITE [a]	TEXAS LIGNITE [b]	WYOMING PRB SUBBITUMINOUS [b]	PA BITUMINOUS [b]
$Na_2O+CaO+MgO+K_2O$ Cyclone Boiler Emissions				
lb/ton	21.04	13.93	2.32	1.17
lb/10^6 Btu	1.5704	0.92	0.14	0.05
lb/dscf	1.5927E-04	9.2941E-05	1.3954E-05	4.6914E-06
lb/wscf	1.3141E-04	7.6686E-05	1.2826E-05	4.3123E-06
Ratio of ND Lignite Cyclone Emissions to Other Cyclones				
Na_2O				
lb/ton		9.7	25.7	52.6
lb/10^6 Btu		11.0	32.6	100.2
lb/dscf		11.0	32.3	99.4
lb/wscf		11.0	29.0	89.2
$Na_2O+CaO+MgO+K_2O$				
lb/ton		1.5	9.1	18.0
lb/10^6 Btu		1.7	11.5	34.2
lb/dscf		1.7	11.4	33.9
lb/wscf		1.7	10.2	30.5
Comparison of ND Lignite Cyclones to Pulverized Units				
Na_2O Emissions				
lb/ton	4.11	0.37	0.80	0.39
lb/10^6 Btu	0.3064	0.0240	0.0471	0.0153
lb/dscf	3.1076E-05	2.4381E-06	4.8117E-06	1.5638E-06
lb/wscf	2.5641E-05	2.0117E-06	4.4228E-06	1.4374E-06
$Na_2O+CaO+MgO+K_2O$ Emissions				
lb/ton	21.04	12.06	11.60	5.85
lb/10^6 Btu	1.5704	0.7933	0.6824	0.2294
lb/dscf	1.5927E-04	8.0457E-05	6.9770E-05	2.3457E-05
lb/wscf	1.3141E-04	6.6385E-05	6.41309E-05	2.15613E-05

Table 4 Continued

	CENTER LIGNITE [a]	TEXAS LIGNITE [b]	WYOMING PRB SUBBITUMINOUS [b]	PA BITUMINOUS [b]
Ratio ND Lignite Cyclone Emissions to Pulverized Units				
Na_2O				
lb/ton		11.2	5.1	10.5
lb/10^6 Btu		12.7	6.5	20.0
lb/dscf		12.7	6.5	19.9
lb/wscf		12.7	5.8	17.8
$Na_2O+CaO+MgO+K_2O$				
lb/ton		1.7	1.8	3.6
lb/10^6 Btu		2.0	2.3	6.8
lb/dscf		2.0	2.3	6.8
lb/wscf		2.0	2.0	6.1

[a] Information from Minnkota's April 16, 2007 submittal.

[b] Data from the USGS National Coal Database and University of Wyoming.

[c] From AP-42, Compilation of Air Pollutant Emission Factors except for Minnkota which is based on actual stack testing.

[d] Emission factor for tangentially and wall-fired units burning lignite is the average of the AP-42 emission factors.

The most useful emission rate calculation is that in terms of pounds per wet standard cubic foot (lb/wscf). This estimated emission rate represents the actual concentration of the constituents in the ductwork leaving the boiler at standard temperature and pressure. The results for both the historical and future (core sample data) scenarios are similar for the total deactivation constituents and for Na_2O. However, Minnkota has indicated that, based on their experience, the actual ash content of future coal could be 2 percentage points higher than the average of the core samples. This would increase the emission rates calculated previously for the future scenario by approximately 25%. Tables 3 and 4 show that the potential for deactivation of the SCR catalyst is much greater for a cyclone boiler combusting Center Mine lignite.

In general, North Dakota lignite has a higher ash sodium content than western subbituminous coal. An exception is subbituminous coal from the Spring Creek Mine near Decker, Montana. Department records indicate the ash sodium content in Spring Creek Mine coal can vary from less than one percent to approximately nine percent. The Department investigated the use of Spring Creek Mine coal by power plants. Based on information supplied by Rio Tinto Energy, operator of the Spring Creek Mine, it was determined that the only power plant that utilizes Spring Creek Mine subbituminous coal and operates an SCR system is the Karn/Weadock Generating Complex in Michigan.

The Department contacted Consumers Energy [14,15], the operator of the Karn/Weadock Generating Complex. The Dan E. Karn Units 1 and 2 burn coal and are equipped with selective catalytic reduction for nitrogen oxides control. Consumers Energy indicated they purchase coal from several western mines as well as eastern mines. They also indicated that none of the coal obtained from the Spring Creek Mine is fed to a unit equipped with an SCR system[15]. Based on this information, the Department is not aware of any power plant that is equipped with an SCR system and burns Spring Creek Mine coal.

The Energy & Environmental Research Center (EERC) at the University of North Dakota is recognized as one of the world's leading coal research facilities. Since 1951, the EERC has focused on research and development, technology demonstration and technology commercialization. As part of the BACT assessment, Minnkota submitted a report by the EERC titled <u>Ash Impacts on SCR Catalyst Performance</u>[5]. In that report, it is stated: "**The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems.**" The report further states: "**Alkali and alkaline earth sulfates are enhanced by cyclone-fired systems. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the fly ash as a result of cyclone firing.**"

In reviewing the flue gas characteristics of plants firing coal types where SCR has been applied with those of the M.R. Young Station, it appears comparison of the characteristics for cyclone fired units alone is more appropriate because of the enhanced sulfates formation in cyclone units. The Department's review suggests that the sodium oxide loading in the flue gas for the North Dakota lignite-fired unit would be nearly 29 times (on a lb/wscf basis) that of a cyclone unit burning PRB subbituminous coal. This ratio is actually conservative (expected to higher) because of the partitioning of the ash that occurs in a cyclone boiler firing North Dakota lignite. The estimated combined loading of catalyst deactivation constituents sodium oxide, calcium oxide, magnesium oxide and potassium oxide is more than ten times that of PRB subbituminous coal-fired cyclone units. Although the deactivation of the SCR catalyst may not be directly proportional to the emission rate, it is evident that the concentration of various SCR deactivation chemical constituents in the flue gas of a North Dakota lignite-fired power plant is much different from a cyclone unit firing PRB subbituminous coal.

When compared to other types of combustion units, the estimated emission rate of Na_2O is approximately six times that of a wall-fired or tangentially fired unit burning subbituminous coal from Wyoming's Powder River Basin. The estimated emission rate of Na_2O, CaO, MgO and K_2O combined is double for the cyclone boiler burning Center Mine lignite. These ratios of emission rates are based on average coal. When Minnkota combusts lignite with a higher ash or sodium content, the ratio will be greater. As can be seen from Table 1, the Na_2O concentration in Center Mine lignite is much more variable than the other coals.

Gutberlet[6] in his technical paper on deactivation of SCR catalyst states: "**Alkaline metals chemically attach to active catalyst pore sites and cause blinding. Sodium (Na) and potassium (K) are of prime concern especially in their water soluble forms which are mobile and penetrate into the catalyst pores.**" Minnkota, in its March 19, 2007 response to questions indicates that most sodium in North Dakota lignite is organically associated. Combustion of the organically associated sodium produces soluble sodium compounds that are readily available for reactions with catalysts and flue gas species. Potassium is associated with clay minerals. Minnkota also stated that in a conversation with Fleming Hansen of Haldor Topsoe (see Minnkota's November 9, 2007 response to comments), Mr. Hansen indicated that sodium was a major concern and that it causes deactivation, especially in the organically associated form. It is evident to the Department that the form (soluble) of sodium present in the ash from the combustion of North Dakota lignite will deactivate an SCR much more quickly than the other types of coals where SCR has been successful.

The next issue to address is whether the difference in these characteristics would preclude the <u>successful</u> operation of SCR technology on units fired on North Dakota lignite.

The NSR Workshop Manual states: "**Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary**". The manual also states: "**A demonstration of technical infeasibility is based on technical assessment considering physical, chemical and engineering principles, and/or emperical data showing that the technology would not work on the emissions unit under review, or that unresolved technically difficulties would preclude the successful deployment of the technique.**" The NSR Manual[1] does not define "successful operation" of the control device or "successful deployment" of the technique.

The EERC, several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station, which is a cyclone fired unit that combusts North Dakota lignite. The pilot scale SCR deployed at the Coyote Station was plugged and the catalyst pores deactivated after 2 months (approx. 1430 hours). The Department believes successful operation is considerably more than a few thousand hours of operation. For example, the EPA Air Pollution Control Cost Manual[2] states: "**For coal-fired boiler applications, SCR catalyst vendors typically guarantee that catalyst for an operating life ranging between 10,000 hours to 30,000 hours.**" In the technical paper Nitrogen Oxides Emission Control Options for Coal Fired Electric Utility Boilers,[9] it is stated: "**On dry-bottom, coal-fired U.S. boilers equipped with full SCR, the planned time between catalyst changes on a typical unit is typically ~ 24,000 operating hours or ≥ 3 years of operations.**" The paper also indicated that Merrimack 2, a cyclone boiler with 100% flyash reinjection, the expected time between the replacement of layers is 14,000 operating hours. It appears that 10,000 hours of operation would be a minimum time for successful operation.

Pritchard[7] states in his paper on optimizing SCR catalyst design: "Our experience show that coal-fired SCRs are successful when the system impact and catalyst deterioration factors are understood and specific counter measures are implemented in system and catalyst design." The Coyote Station pilot test may not have provided much useful data for designing an SCR system for plants firing North Dakota lignite; however, it did indicate a difference between lignite and subbituminous coal. The pilot scale testing protocol was the same for the Coyote Station, Columbia Station and Baldwin Station; however, the test at the Columbia Station used a different catalyst. The Coyote Station combusts lignite while the Columbia Station and Baldwin Station fire subbituminous coal. The EERC has described the blinding and plugging (deactivation) at the Coyote Station as extremely rapid and severe as compared to testing at the Columbia and Baldwin Stations. This indicates to the Department that design of an SCR system for North Dakota lignite would be different from a unit burning subbituminous coal. Because of the lack of deactivation data from the pilot test at the Coyote Station, it would appear to be extremely difficult to design an SCR system that could be successfully operated. Proceeding with installation of such a design without engineering data collected during appropriate pilot testing is subject to an extreme risk. This suggests to the Department that additional research and testing on the effects of the flue gas constituents are required to design the SCR system.

Besides catalyst deactivation, Minnkota believes that a high-dust SCR would experience plugging problems due to the deposition characteristics of

North Dakota lignite (sticky ash) and the carry over of "popcorn ash" from the boiler. The deposition characteristics of the ash from combusting lignite will create difficult to remove ash deposits and will increase deposition in the air preheater downstream and flue gas duct work, which could be severe. Popcorn ash is generated during cleaning actions within the boiler which are quite frequent due to the characteristics of North Dakota lignite. Although there have been advances made in the last few years for controlling popcorn ash, these advances may or may not be applicable to a cyclone boiler burning North Dakota lignite. Extensive engineering analyses, and perhaps pilot scale testing, will be necessary to determine if these advances can be applied at the M.R. Young Station.

The flue gas temperature variation at the location a high dust SCR would be placed is also a concern. Minnkota indicates that the temperature generally ranges from approximately 430°F to 960°F for Unit 1 depending on the unit's load. For Unit 2, it could vary from 430-880°F. However, temperatures as high as 1050°F at Unit 1 and 990°F at Unit 2 have been measured.

The EPA Air Pollution Control Cost Manual[2] states: **"The NO_x reduction reaction is effective only within a given temperature range. The use of a catalyst in the SCR process lowers the temperature range required to maximize the NO_x reduction reaction. At temperatures below the specified range, the reaction kinetics decrease and ammonia passes through the boiler (ammonia slip). At temperatures above the specified range, nitrous oxide (N_2O) forms and catalyst sintering and deactivation occurs.**

In an SCR system, the optimum temperature depends on both the type of catalyst utilized in the process and the flue gas composition. For the majority of commercial catalysts (metal oxides), the optimum temperatures for the SCR process range from 480°F to 800°F (250°C to 427°C). The figure shows that the rate of the NO_x removal increases with temperatures up to a maximum between 700°F to 750°F (370°C to 400°C)" (figure omitted here).

The Control Cost Manual[2] goes on to state: "**The relationships between flue gas temperature, catalyst volume, and NO_x removal are complicated functions of the catalyst formulation and configuration. The physical and chemical properties of each catalyst are optimized for a different operating conditions. For a given catalyst formulation, the required catalyst volume and/or temperature range can even change from one manufacturer of the catalyst to another. The selection of catalyst, therefore, is critical to the operation and performance of the SCR system.**"

This complicated relationship suggests that additional research, design and testing may be required before the temperature problem could be overcome. Minnkota has provided a "concept" for solving the temperature problems; however, engineering studies would have to be conducted before it is known whether the temperature problem (temperatures both below and above the optimum temperature window) could be overcome.

The final reason Minnkota cited for technical infeasibility was erosion of the catalyst. Because of the high ash content and anticipated frequent cleaning cycles due to the deposition characteristics of North Dakota lignite ash, erosion may be more of a concern than with a bituminous or subbituminous coal-fired unit. Pilot scale testing is now underway at the Sandow Plant in Texas. This facility also burns lignite. The results of that testing may provide information that Minnkota can apply to the design of an SCR system to control erosion; however, the results are not available at this time. Again, the Department believes additional design work and testing may be required for successful application of SCR technology to North Dakota lignite-fired units.

The BACT assessment for Minnkota was prepared by Burns and McDonnell, which has considerable experience with SCR systems, and the EERC, which has extensive experience with North Dakota lignite. Sargeant and Lundy, LLC (S&L), another consulting firm acting on behalf of Basin Electric Power Cooperative, also made a presentation to the Department on the application of SCR technology to North Dakota lignite fuels. S&L indicated it had designed 46% of the SCR system in the United States. Of the SCR systems, 39 were for coal-fired units with 10 designed for Powder River Basin subbituminous coal. S&L listed[8] their "Keys to Achieving Success" as:

- Understand deactivation mechanisms
- Understand ash behavior
- The "Understanding" establishes:
    - Catalyst formulation
    - Catalyst pitch
    - Reactor velocity
    - Catalyst surface and volume

- Results in reactor size and shape to match catalyst management plan
- Physical model for:
  - NH_3 and NO_x mixing
  - Gas distribution and velocity profile
- CFD modeling:
  - Identify and mitigate areas of potential ash deposits
  - Mixing gases of different temperatures

S&L also provided possible solutions for deactivation of the catalyst. However, they indicated there was no known solution for deactivation due to soluble alkalis such as the soluble sodium compounds generated by the combustion of North Dakota lignite. S&L speculated that more catalyst and a larger reactor may be possible solutions; however, how much more catalyst or how much larger the reactor would have to be to solve the problem was unknown. S&L also pointed out that some design issues for North Dakota have not been addressed by Powder River Basin experience. Some of these issues include:

- The high level of soluble alkali in North Dakota lignite
- The particle size and sticky nature of high alkaline North Dakota lignite
- Potential abrasive qualities of North Dakota lignite ash

S&L concluded their presentation with the following statement about North Dakota lignite: "**There are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance.**" S&L

recommendations included a parametric pilot test program to:

Answer questions on:

- soluble alkalis
- ash characteristics
    - size
    - stickiness
    - abrasive qualities
- Compare findings with PRB experience.

The NSR Manual[1] describes the process commonly used for bringing a control technology concept to reality as a commercial product as follows:

- **concept stage**
- **research and patenting**
- **bench scale or laboratory testing**
- **pilot scale testing**
- **licensing and commercial demonstration**
- **commercial sales**

"A control technique is considered available (and thus technically feasible), within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new or dissimilar source type."

"Commercial availability by itself, however, is not necessarily sufficient bases for concluding a

technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or applicable to the source type under consideration."

The NSR Manual[1] also states: **"Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasiblity, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, decisions about technical feasibility will be based on chemical and engineering analyses (as discussed below) in conjunction with information about vendor guarantees."**

Minnkota solicited information from SCR and catalyst vendors via an SCR Vendor Query Information Request (see Appendix A of Minnkota's April 18, 2007 response to NDDH and EPA comments). On May 8, 2008, Minnkota provided additional information and a discussion of the responses received[16]. Some of the vendor responses indicate a higher degree of confidence about the successful use of SCR at the M.R. Young Station while others were less optimistic. However, all responses indicated the following:

1) The need for additional testing to either determine if there were any fatal flaws or to obtain data for the design of a potentially successful SCR system.

2) The temperature problem (both too low and too high) had to be resolved for a successful application of a high dust SCR.

3) "Make good" guarantees were not provided.

The vendors that were more optimistic included Alstom Power, Haldor Topsoe and CERAM Environmental, Inc. Alstom Power indicated they would offer a guarantee of 16,000 hours between catalyst changeout and Haldor Topsoe expects greater than 60% deactivation over the first 10,000 operating hours. These estimates appears to be based on their experience with wood-fired boilers and that the SCR system would operate between 600-750°F. Alstom Power suggested that up to 90% NO_x removal efficiency could be obtained; however, they did not indicate any guarantee of removal efficiency (performance guarantee). Minnkota disputes the assertion that wood-fired ash is comparable to the ash at the M.R. Young Station. Minnkota indicates that the alkali in the lignite flyash is in the form of oxide/hydroxide and partially sulfated form while the alkali in the flyash from wood would be in a different form, such as chloride. The Department also questions whether the loading of catalyst poisons would be comparable. AP-42[4], Section 1.6, provides emission factors for wood residue combustion in boilers. Table 1.6-4 lists as emission factor for sodium of 0.00036 $lb/10^6$ Btu as compared to Center lignite burned in a cyclone boiler of 0.3008 $lb/10^6$ Btu (see table 3). The factor in AP-42[4] is based on data from boilers with and without particulate control devices. Even if you assume 99% control efficiency of sodium by the particulate control device (which is very unlikely), the emission factor for Center lignite is still more than eight times larger. The Department believes the experience with wood-fired boilers has questionable application to a boiler firing North Dakota lignite.

CERAM Environmental (CERAM) initially provided a design of an SCR system based on 85% NO_x reduction efficiency with a catalyst life guarantee of 16,000 hours. After further discussions with Burns and McDonnell, CERAM stated "**However, considering some of the remaining uncertainties we would recommend further testing to ensure a successful result.**"

The vendor information indicates to the Department that additional testing will be required to:

1) Obtain design data to determine if SCR can be successfully applied.

2) Obtain catalyst deactivation data.

3) Obtain data to predict the controlled NO_x emission rate (control efficiency data).

In addition to the catalyst testing, the vendor information indicates that the temperature problem for a high dust SCR must be resolved in order to have any chance of successfully applying this technology to the M.R. Young Station. This will require a detailed engineering study. Minnkota is not required to do this testing or engineering study as part of the BACT determination process.

Summary:

The characteristics of the exhaust, or flue gas stream, after combustion of fuel by a boiler are governed by the design and operating characteristics of the boiler and the characteristics of the fuel. In this scenario, the boilers are cyclones and the fuel is North Dakota (Fort Union) lignite. Minnkota concluded in its NO_x BACT analyses that available SCR catalysts are not applicable for the M.R. Young Station (MRYS).

One foremost issue in the NO_x BACT analyses is whether any unique characteristics due to lignite fired by cyclone boilers are cause for doubt that known SCR technology is not applicable and technically infeasible. In words that parallel EPA in its review of Minnkota supplied information, does available information and data show that the gas stream has unique qualities different than gas streams of other coal-fired boilers. If so, does this then cause unique catalyst deposition, erosion, poisoning, blinding (or fouling or surface masking) and plugging that are unresolvable barriers in the ability of known SCR technologies to control NO_x stack emissions, which makes SCR an ineffective NO_x control system?

The written record following Minnkota's BACT analyses contains substantial supplemental information provided by Minnkota. We note that plugging of a catalyst on its face due to deposition of particles larger than the pitch of a catalyst (a.k.a. catalyst channel blockage) and plugging of pores on surfaces of a catalyst are generally different physical interactions. Our review of the supplemental information concludes that the following facts are not disputed by EPA.

1) In cyclone firing of Fort Union lignite and Center Mine coal, about 45 to 50% of the ash forming components of the coal end up as flue-gas ash. Unburned or partially burned organic fraction of the Fort Union lignite, which contains more sodium than other coals, reacts with silicate particles causing a "stickiness" quality of flue gas ash, which results in ash deposits on heat transfer surfaces. Larger particles from the deposits fracture on heat-transfer surfaces (a.k.a. popcorn ash) at a higher rate and enter the flue gas stream. Consequently, due to the stickiness of the lignite ash, a higher rate of deposition on surfaces of catalytic reactors occurs compared to other coal and boiler scenarios, as reported by Minnkota.

2) Fort Union lignite, and the Center Mine coal, has a higher moisture content and is oxygen rich compared to other coal types. This lignite also has a higher sulfur content compared to PRB coal. Consequently, the flue gas stream is rich in sulfur dioxide (SO_2) and sulfate (SO_4) compared to other coal types.

3) Fort Union lignite, and the Center Mine coal, has a higher organic matter content compared to other coal types. This lignite contains a higher proportion of alkali metal constituents, especially sodium (Na). Cyclone combustion of the coal produces ash, which is partitioned as slag on high temperature boiler surfaces due to cyclonic air circulation and

as flue gas vapor and fine particles (less than 15 micrometers (microns)). About 75% of total sodium in the lignite is associated with the organic fraction of the lignite, the remaining sodium is water soluble; so very little of the sodium is associated with the mineral fraction of the lignite such as clays. During combustion, organic and water-soluble sodium vaporizes. Consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.

4) Alkali vapors condense (homogeneous nucleation) due to flue-gas cooling or react (heterogeneous nucleation) with other flue gas constituents, e.g., mineral silicates and sulfate. Evidence for these reactions is found in morphological data from filter samples of flue gas taken at the MRYS. The size distribution of flue gas particles is bi-model, relating to organically associated inorganics in coal and coalesced minerals and inorganics in flue gas; the size distribution varies by coal type and combustion method.

5) NO_x reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 or 2 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO_x. Residual alkali vapors, Na, potassium (K) and calcium (Ca) displace hydrogen (H) on fresh catalyst, which prevents catalytic reaction

with NO_x (a.k.a poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging, which requires more frequen~~cy~~t catalyst maintenance.

6) There are no SCR systems planned, constructed or operating in the flue gas stream of cyclone boilers fired with Fort Union lignite. Fort Union lignite has some coal characteristics that are uniquely different than Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, specifically sodium, with that organic matter.

7) Slipstream SCR reactors of the same design were installed at two power plants to test SCR for NO_x emissions control. One of the plants was cyclone fired with Fort Union lignite and the other with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

8) There may be an engineering solution to reduce deposition on the surface of catalytic

reactors. But there is no known in-reactor engineering solution to:

(a) reduce deactivation rates caused by heterogeneous reactions that form the particles that cause pore blinding and plugging, or

(b) to restore the catalytic reactions by removing particles from catalyst pores.

9) There are no usable data for rates of deactivation of SCR catalyst in the flue gas of cyclone combustion of Fort Union lignite and Center Mine coal. Catalyst pitch is the only apparent catalyst geometric affecting ash deposition; but pitch also affects flue gas velocity through the reactor and, thus, times of exposure of NO_x for reduction to nitrogen (N_2) and water (H_20).

10) There are several factors relevant to Minnkota's MRYS, such as locations of economizers and air pre-heaters, that require engineering design solutions before SCR could be considered as a viable control technology. The NSR Manual[1] does not provide specific numeric performance measures that an SCR NO_x control technology must achieve to satisfy the manual's applicable (technically feasible) criteria.

Companion issues include ammonia slip and pyrosulfates emitted from a high-dust SCR will exaggerate flue-gas particulate (ash) deposits on low-temperature convective pass surfaces in the economizer and the primary air pre-heaters.

Our review of the supplemental information concludes that EPA generally disagrees with Minnkota's perspective on some relevant issues relating to cyclone boiler and heat exchanger systems, and flue gas characteristics that can impact SCR catalyst performance. In summary, Minnkota asserts:

1) Center Mine coal fired in the Minnkota cyclone units has important time variable ash content and ash constituent concentrations that must be included in the technical assessment of SCR applicability and feasibility. An engineering focus on single constituents alone or on average constituents can cause significant SCR design errors.

2) The flue gas ash characteristics of Center Mine coal-fired cyclones and current catalyst geometries are expected to create a required aggressive on-line cleaning of the catalyst and frequent catalyst replacement resulting in forced boiler outages.

3) The geometries of catalysts have not been improved to minimize vapor phase and small particle deposition and plugging within the pores of catalyst[s]. The pores are prone to filling through the transport processes of diffusion and impaction, and the flue-gas rich in sodium, as well as other alkali, greatly increases rates of catalyst deactivation. Adjusting catalyst pitch alone to accommodate the particulate in the flue gas does not address the higher flue-gas sodium whether in a high dust or low dust SCR application. A larger pitch reduces flue gas velocity and

increases the sodium vapor phase and small particle diffusion into pores of the catalyst.

4) SCR catalyst vendors are not willing to guarantee performance of their respective catalysts in a Center Mine coal-fired cyclone boiler application. For example, there has been no work by catalyst vendors that has advanced SCR systems for high sodium applications.

Our review of the supplemental information concludes that Minnkota generally is concerned with or disagrees with EPA's perspective on some relevant issues relating to cyclone boiler and heat exchanger systems and flue gas characteristics that can impact SCR catalyst performance. In summary, EPA asserts:

1) Minnkota has not provided information that "shows that ... [deposition] and deactivation of the SCR catalyst is an unresolvable technical barrier and/or the ability of an SCR to control NO_x would be so limited that SCR would be an ineffective control option." "A lack of a full-scale long-term commercial SCR installation at a facility with similar sodium levels in the fuel is not evidence that SCR is technically infeasible." The expected SCR problems described by Minnkota are "more a matter of cost than technical feasibility."

2) The success of SCR technology applied to cyclone boilers as a source category is demonstrated to be technically feasible for coal types other than Fort Union lignite. And successes and failures of PRB-fired cyclone

boilers provides "valuable information for designing an SCR system on a plant burning North Dakota lignite." "There are engineering challenges with operating an SCR system at MRYS, ... these would largely be a matter of cost and should be examined under step 4 of the Top-Down BACT analysis." For example, SCR maintenance and downtime do "not render the technology technically infeasible". Refinements of engineering solutions to the affects of flue gas characteristics due to Center Mine coal-fired cyclones on the catalyst can been implemented following start up of an SCR system.

<u>Conclusions</u>:

The Department has completed an extensive review of all aspects of the application of SCR technology to the M.R. Young Station. Whether the problems associated with adapting SCR technology to a cyclone unit firing North Dakota lignite can be overcome is highly speculative.

The Department makes the following conclusions:

1) Lignite from the Center Mine is extremely variable in heat content, ash content, and in the constituents that make up the ash. This variability will affect the design and operation of an SCR system.

2) The only pilot scale testing that has ever been conducted on a unit firing North Dakota lignite was at the Coyote Station. The pilot scale SCR plugged after only 2 months and little useful data was obtained. However, the

testing used the same protocol as testing at the Columbia and Baldwin Station which had fewer problems. The Columbia and Baldwin Stations burn subbituminous coal. The Coyote testing demonstrates to the Department that North Dakota lignite firing will have more severe effects (plugging and catalyst deactivation) than units firing subbituminous coal when the same design is employed. Operation of an SCR system for only 2 months between catalyst change out is much less time than is normally expected (at least 10,000 hours or 13.7 months) for power plants. Operation of an SCR system for only 2 months between catalyst replacement is not considered successful operation of SCR technology. Without pilot scale testing, the life of the catalyst cannot be predicted with any reasonable certainty.

3) North Dakota lignite contains primarily organic sodium compounds. The combustion of the lignite produces soluble sodium compounds which causes more severe catalyst deactivation problems than insoluble sodium compounds.

4) The flue gas constituents that cause SCR catalyst deactivation at the M.R. Young Station are significantly different from Texas lignite, Wyoming PRB subbituminous coal, and Pennsylvania bituminous coal. When cyclone boilers combusting North Dakota lignite are compared to any other type of combustion unit burning the other types of coal, the concentration of sodium compounds in the flue gas is at least 6 times greater (based on average coal and lb/wscf basis) than the other

types of fuel and the total primary alkali constituents (CaO, Na_2O, MgO and K_2O) are approximately double. The flue gas generated at the M.R. Young Station is different from the flue gas at any plant where SCR technology has been applied, primarily due to the high concentration of soluble sodium compounds and the total flue gas loading of catalyst deactivation chemicals. This difference in flue gas characteristics will preclude the successful application of existing SCR technology to the M.R. Young Station. Additional pilot scale testing is necessary to learn if the technology can be adapted.

5) Both Burns and McDonnell and Sargent and Lundy have extensive experience with the design and operation of SCR systems. Burns and McDonnell has expressed concerns whether an SCR system can be successfully designed and operated at a cyclone boiler combusting North Dakota lignite. S&L has indicated that certain design issues have not been addressed by PRB (subbituminous coal) experience. They have also indicated that some important unanswered questions pose significant risks for an SCR design engineer and recommended pilot scale testing before design takes place.

6) The NSR Manual[1] lists the stages in the development of a commercial control system from concept stage to commercial sales. Experimentation with the SCR system takes place during the bench scale/laboratory testing or pilot scale testing stages. Although adjustments of full scale (commercial product) units is often necessary, the source

operator should not be required at this stage to conduct experimentation in order to make the equipment work. This could cause extended time delays and resource penalties for the source operator. To design and install an SCR system for a cyclone unit firing North Dakota lignite without obtaining additional data from bench scale or pilot scale testing would be experimentation.

7) The temperature variation of the flue gas entering the SCR will adversely affect performance and must be resolved for successful application of this technology. Engineering studies will be required to determine if this problem can be resolved. Minnkota is not required to experience extended time delays or resource penalties to allow research to be conducted. Neither is Minnkota required to experience extended trials to learn how to apply a technology. The temperature problems for the SCR will require extensive, and correspondingly expensive, engineering studies to determine if this problem can be resolved.

8) There are unresolved issues regarding catalyst erosion from the ash generated at the M.R. Young Station. The pilot testing being conducted in Texas may or may not resolve issues regarding abrasion of the catalyst by the ash in the flue gas. However, that data is not available at this time. If it does not resolve the abrasion issues, additional pilot testing will be required to determine if SCR technology can be successfully adapted to the M.R. Young Station. Minnkota is not required

to conduct this pilot testing. This testing may also prove that SCR technology is not feasible for lignite combustion.

9) Poisoning, blinding and plugging of a catalyst are affected by the geometries and properties of the catalyst. Cyclone firing of Fort Union lignite and Center Mine coal results in a flue gas stream that highly accelerates poisoning, blinding and plugging (of pores) due to the rich sodium and potassium vapors, particles and ammonia sulfates (due to ammonia injection) in lignite-fired cyclone flue gas. The engineering solutions of a larger SCR reactor, more catalyst and larger pitch do not resolve the rapid plugging of catalyst pores, at least with some certainty to assure a predictable useful life of catalyst before change out. There is no catalyst vendor solution to reduce or eliminate catalyst pore plugging. The chemical and physical process of pore plugging cannot be reversed, which dictates catalyst change out.

10) Without pilot scale testing, the long term NO_x reduction efficiency, the volume of the reactor, the catalyst pitch, life of the catalyst, or even the type of catalyst to be used cannot be predicted with a high degree of confidence. Sargent and Lundy has pointed out that to design an SCR system for a plant burning North Dakota lignite without pilot scale testing would present significant risks for the SCR design engineer. Without these design factors determined, any cost estimate would be conjecture and any evaluation of cost effectiveness or incremental cost in Step 4 of

the BACT analysis would be meaningless. Minnkota is not required to conduct pilot testing to obtain this data.

11) SCR technologies have not been installed full-scale on a boiler firing North Dakota (or similar) lignite; in fact, vendors cannot without further pilot testing, guarantee SCR system performance for M.R. Young Station boilers firing North Dakota lignite. Even the most optimistic vendors don't offer true guarantees of catalyst performance; rather, the guarantee is limited to the contact value and contract value is a small portion of a typical full-scale SCR system installation.

All vendors admit that additional pilot testing would be needed (the best estimates that would take about one year), and the NSR Manual notes that "**technologies in the pilot scale testing stages of development would not be considered available for BACT review.**" Some vendors have suggested that catalyst life might be in the vicinity of 16,000 hours between replacements (another has estimated about 10,000 hours, but this is based on boilers firing wood with SCR that has 5-10 times less fly-ash, and 70-80 times less sulfur), but significantly these are guesses rather than guarantees.

11) The NSR Manual[1] states: "In practice, decisions about technical feasibility are within the purview of the review authority." The review authority is the North Dakota Department of Health.

Therefore, the Department has determined, based on guidance in Chapter B of the NSR Manual[1], that high dust SCR technology is not technically feasible at this time for both units at the M.R. Young Station.

b. **Low Dust and Tail Gas SCR**

Catalyst Deactivation:

The problems associated with a low-dust SCR or a tail-gas SCR are similar. Minnkota's analysis list them as:

- Catalyst Fouling and Deactivation
- Site Space Constraints
- Reheat of Flue Gas

Catalyst deactivation would be primarily due to alkali mineral compounds that are not removed by the ESP or SO_2 scrubbing system. These include sodium and calcium sulfates that were discussed previously. The Department has had some experience with sodium compounds passing through air pollution control devices. The Minn-Dak Farmer's Coop. operates two coal-fired boilers that are equipped with a mechanical collector and wet scrubber for particulate matter and SO_2 control. Minn-Dak had trouble complying with its particulate matter emission limit (45.5 lb/hr which equates to 0.10 lb/10^6 Btu) due to sodium compounds passing through the air pollution control devices. In order to maintain compliance, the ash Na_2O content of the coal combusted had to be limited to 2.8% (dry basis). This has been established as a fuel restriction within Minn-Dak's Title V Permit to Operate.

Minnkota, in its November 9, 2007 response to comments, provided evidence of sodium and potassium compounds that deposited downstream of the electrostatic precipitator on Unit 1. This indicates that the electrostatic precipitator will not remove all of the submicron sodium particles that are generated by the combustion of Center lignite. Given the high expected emission rate of sodium compounds (see Table 3), it appears a significant amount of sodium compounds, a catalyst poison, will enter a low dust or tail gas SCR system.

The deactivation issue for low-dust and tail-gas SCR remains as with the high-dust SCR. The research, design and pilot testing needed to develop an SCR system that will have reasonable success makes this technology also not applicable at this time.

Site Constraints:

The NSR Manual[1] states: "Also a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g. size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology feasible."

Minnkota has not indicated that the site constraints are unresolvable. Therefore, this issue appears to be an economic consideration instead of a technical feasibility issue.

Reheat of the Flue Gas:

Minnkota has not indicated there are any unresolvable constraints to reheating the flue gas. Again, this appears to be an economic issue instead of a technical feasibility issue. One issue with reheat is the generation of additional air contaminant emissions. Depending on the fuel used for reheat, emissions of NO_x, SO_2, particulate matter, carbon monoxide and volatile organic compounds could increase. This increase in emissions would be an issue if low-dust for tail-gas SCR were considered technically feasible.

In summary, the Department believes that catalyst deactivation of a low-dust or tail-gas SCR due to alkali compounds is an issue that will require extensive research, design and pilot testing to determine whether the technology can be successfully applied to units fired on North Dakota lignite. Therefore, these technologies are not considered applicable and not technically feasible at this time.

3. **Electro - Catalytic Oxidation (ECO®)**

Electro - catalytic oxidation (ECO®) is a multi-pollutant central system that utilizes a reactor for oxidation of pollutants, an absorber vessel for SO_2 and NO_x removal and a wet electrostatic precipitator for removal of acid aerosols, fine particulate matter and oxidized mercury. The process has been demonstrated at First Energy's R.E. Burger Plant in Shadyside, Ohio. This demonstration was a slipstream operation that was approximately equivalent to 50 MWe. The boiler was a front wall-fired unit that combusted eastern bituminous coal. A 215 MWe project is scheduled for the Bay Shore Plant in Oregon, Ohio.

A pilot scale test of the ECO reactor was conducted at M.R. Young Station starting in July, 2007. The system, which was designed by Powerspan Corporation and the UND EERC, was placed downstream of the Unit 1 electrostatic precipitator. The final report[11] for the testing indicates that sodium-rich aerosols and small ash particles accumulated and became bonded on the surface of the silica electrodes. Within a two-week period, the sodium and ash accumulation reduced the NO_x conversion efficiency from greater than 90% to less than 40%. The use of an acoustic horn was ineffective in eliminating the sodium and ash accumulation. There is no proven method for cleaning the electrodes without removing the electrodes from the reactor. The Department believes that extensive testing would be required to determine a method for in-situ cleaning of the electrodes or reduction of the sodium/ash particles. Therefore, the technology is not considered technically feasible at this time.

4. **Rich Reagent Injection (RRI) with Advanced Separated Overfire Air with or without SNCR**

Minnkota has indicated that the use of RRI has insurmountable problems which makes it technically infeasible. This is primarily due to the inability to control the air/fuel proportions to ensure that a stoichiometric ratio of under 1 is maintained at all cyclones. If the stoichiometric ratio is too far below 1, fuel ash will be solidified in the cyclone barrel. If the stoichiometric ratio is above 1, the oxygen in the excess air will oxidize the reagent (urea) and produce additional NO_x emissions. The inability to control the stoichiometric ratio is due to the highly variable quality of the lignite combusted. Minnkota has provided data which shows as much as 12% difference in heating value between lignite fed to individual cyclones at the same time.

The current configuration of the furnaces at the M.R. Young Station is incompatible with RRI. The reagent injection would be near the elevation of the existing lignite drying system vent ports. The oxygen introduced with the lignite drying systems air stream would cause the reagent to be oxidized which would increase NO_x emissions.

Minnkota has operated the M.R. Young Station since 1970 using lignite from the Center Mine. Minnkota's experience operating the plant with the quality of the lignite supplied is persuasive in determining the feasibility of this technology. RRI may not reduce NO_x emissions and could actually increase emissions. Extensive testing would be required to determine if this technology could be successfully applied to the M.R. Young Station. The Department concurs with Minnkota's determination that RRI is not technically feasible and RRI will not be considered further.

5. **SNCR and Fuel Reburn**

To the Department's knowledge, only one permanent application of conventional gas reburn and SNCR is known. It was applied to a tangentially fired boiler at the Somerset Station. The Somerset Station fires eastern bituminous coal and is a relatively small utility unit rated at 120 megawatts. The Minnkota units are cyclone-fired, more than twice as large as the Somerset boiler, and fire North Dakota lignite. The NSR Manual[2] states: **"For process type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source**

and other sources to which the technique had been applied previously." The lack of experience and the differences between Minnkota and Somerset indicate that the effectiveness of this technology when applied to the units at the M.R. Young Station is unknown. Minnkota is not required to experience extended trials to learn how to apply this technology. Therefore, the Department considers this technology not available for a cyclone boiler burning North Dakota lignite and thus infeasible.

6. **Fuel-Lean Gas Reburn (FLGR™) plus SNCR**

No actual demonstration or permanent installations on cyclone boilers were found. Minnkota's analysis stated that a technical paper on FLGR™ indicated the technology when used alone provided only a 27% reduction in NO_x emissions. This is less than other technologies such as ASOFA (40%). Thus, ASOFA plus SNCR will be a superior option for controlling NO_x. The combination of FLGR™ plus SNCR has not been demonstrated on a cyclone boiler. Because of inferior expected NO_x removal efficiency and the lack of commercial application to a cyclone boiler, this option was not considered further.

7. **Oxygen - Enhanced Combustion**

This technology has only been demonstrated on a pulverized unit (non-cyclone) firing bituminous coal. The testing indicated a reduction efficiency of approximately 38% down to approximately 20% as the stoichiometric ratio approached 1.0.[12] This technology has not been demonstrated on either a temporary or permanent basis for a cyclone boiler burning any type of coal or on boilers as large as those at the M.R. Young Station, and the NO_x reduction is less than ASOFA (40%). The Department believes the technology is not available, is inferior to other options and will not be considered further.

8. **Water/Steam Injection**

Because of the high moisture content of the lignite (35-40%) combusted and the need to ignite and sustain stable combustion and molten slag in the cyclones, this technology is considered technically infeasible.

9. **Hydrocarbon Enhanced SNCR (HE-SNCR)**

HE-SNCR uses an ammonia-based reagent which is continuously injected (through a grid) into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (usually natural gas or propane). Doosan Babcock Energy marketed a commercial version of HE-SNCR as NO_x Star™ and claimed NO_x reductions up to 70%. Actual experience indicates NO_x reduction efficiencies of 68 - 80% when used in combination with overfire air and air staged combustion. There is no data for use of HE-SNCR alone.

NO_x Star™ has been installed on a tangentially fired boiler and a wall fired unit, both burning eastern bituminous coal. It appears this technology has never been applied to a cyclone boiler or any unit burning subbituminous coal or lignite. Minnkota has indicated that the fouling characteristics of their ash and varying loads would create problems for the successful use of this technology. The Department reviewed several BART determinations for power plants in other states that are burning western subbituminous coal. Several analyses did not list this technology as being available, some listed it as in the pilot scale stage for subbituminous coal and one analysis indicated that it is currently not being marketed. The Department contacted Doosan Babcock and confirmed that they are not currently marketing the NO_x Star™ technology because it did not provide sufficient NO_x removal efficiency.[10]

The fouling characteristics of Center lignite are well documented. The variability of the Center lignite (which affects load) has also been documented in Minnkota's responses to comments on its BACT analysis. These problems and the lack of experience with cyclone boilers and subbituminous coal/lignite will require extensive testing and engineering analysis to determine if the technology can be successfully applied to the boilers at the M.R. Young Station. These issues plus the lack of a commercial vendor indicates the technology is not commercially available for this application and thus technically infeasible.

10. **Other Technologies**

The following technologies are considered technically feasible:

SNCR
SNCR w/SOFA or W/ASOFA
Conventional Gas Reburn
Coal Reburn
Fuel Lean Gas Reburn
ASOFA
SOFA
Combustion Improvements (included with SOFA)
Flue Gas Recirculation (not expected to reduce NO_x)

C. Step 3: **Rank Remaining Control Technologies by Control Effectiveness**

The top technologies are as follows:

Technology	Unit 1 Reduction (%)	Unit 2 Reduction (%)
SNCR w/ASOFA	58	58
Gas Reburn w/ASOFA	56	55
Lignite Reburn w/ASOFA	55	54
Fuel Lean Gas Reburn w/ASOFA	46	45
ASOFA	40	38

Minnkota has indicated that ASOFA will achieve approximately 40% reduction of NO_x emissions at Unit 1 and 38% at Unit 2. They have also indicated that SNCR w/ASOFA will achieve an overall efficiency of 58% at each unit. This equates to an additional 31% removal for Unit 1 and 33% for Unit 2 by using a combination of ASOFA and SNCR instead of just ASOFA. The EPA Air Pollution Control Cost Manual[2] indicates that SNCR, in typical field applications, provides 30-50% NO_x reduction. Although the removal efficiencies for SNCR are lower than expected at new facilities, it is still within EPA's expected range.

Table 5
Emissions Reductions

		Annual Average Baseline Emission Rate		**Annual Average Controlled Emission Rate**	
Unit	**Technology**	**lb/10^6 Btu**	**Tons/Yr**	**lb/10^6 Btu**	**Tons/yr**
1	SNCR w/ASOFA	0.849	9934	0.355	4025
1	Gas Reburn w/ASOFA	0.849	9934	0.374	4275
1	Lignite Reburn w/ASOFA	0.849	9934	0.385	4343
1	FLGR w/ASOFA	0.849	9934	0.460	5260

1	ASOFA	0.849	9934	0.513	5874
2	SNCR w/ASOFA	0.786	15792	0.330	6418
2	Gas Reburn w/ASOFA	0.786	15792	0.350	6883
2	Lignite Reburn w/SOFA	0.786	15792	0.360	6821
2	FLGR w/ASOFA	0.786	15792	0.432	8441
2	ASOFA	0.786	15792	0.489	9651

D. Step 4: **Evaluate Most Effective Controls and Document Results**

Minnkota has provided a detailed cost estimate of the various options in Section 3.4 of each analysis. The costs are summarized as follows:

Table 6
Costs

Unit	Alternative	NO_x Reduction (tons/yr)	Annualized Cost	Control Cost ($/ton)
1	SNCR w/ASOFA	5909	7,472,000	1265
1	Gas Reburn w/ASOFA	5659	37,334,000	6597
1	Lignite Reburn w/ASOFA	5591	11,388,000	2037
1	FLGR w/ASOFA	4674	16,999,000	3635
1	ASOFA	4060	2,490,000	613
2	SNCR w/ASOFA	9374	11,405,000	1217
2	Gas Reburn w/ASOFA	8909	63,883,000	7171
2	Lignite Reburn w/ASOFA	8871	19,475,000	2195
2	FLGR w/ASOFA	7351	29,313,000	3988
2	ASOFA	6141	4,376,000	713

Minnkota also evaluated the energy and environmental impacts associated with each control alternative for both units. The use of SNCR will cause increased emissions of ammonia (ammonia slip). However, the amount of emissions can generally be limited to less than 10 ppm. Advanced separated over fire air may cause a slight increase in carbon monoxide emissions. Based on the analysis, the Department concludes that the energy and environmental impacts would not preclude the selection of any of the alternatives as BACT.

E. **Step 5: Select BACT**

Minnkota has proposed that the most efficient technically feasible control alternative (SNCR w/ASOFA) is BACT and has proposed emission limits. All of the analyses for the BACT determinations were conducted using 12-month rolling average emission rates. This was done for ease of conducting the economic analysis which utilizes annual emissions. The Consent Decree specifies in paragraph 66 that the BACT limit must be on a 30-day rolling average basis. Minnkota has proposed the following limits:

Unit	12-month Rolling Average ($lb/10^6$ Btu)	Proposed BACT Limit ($lb/10^6$ Btu-30.d.r.a.)
1	0.355	0.360
2	0.33	0.350

The Department has evaluated the continuous emissions monitor data for 2004 and 2005 for both units at the M.R. Young Station. The evaluation indicated that the maximum 30-day rolling average was approximately 104% of the annual average emission rate for Unit 1 and approximately 106% for Unit 2. Based on this evaluation, it appears the proposed 30-day rolling average emission limits are appropriate based on the annual average emission rates evaluated.

The proposed limits are based on continuous operation of the boiler. Electric utility boilers are subject to malfunctions, scheduled outages or other situations which require shutdown and eventual startup. During startup, NO_x emissions can be significantly higher than during normal operations. Minnkota has proposed the installation of SNCR with advanced separated overfire air. The EPA Air Pollution Control Cost Manual[2] states:

"The NO_x reduction reaction occurs within a specific temperature range where adequate heat is available to drive the reaction. At lower temperatures the reaction kinetics are slow and ammonia passes through the boiler (ammonia slip). At higher temperatures the reagent oxidizes and additional NO_x is generated. The temperature window is dependent on the reagent utilized. Figure 1.3 shows the NO_x reduction efficiency for urea and ammonia SNCR at various boiler temperatures. For ammonia, the optimum temperature is from 870°C to 1100°C (1600°F to 2000°F)."

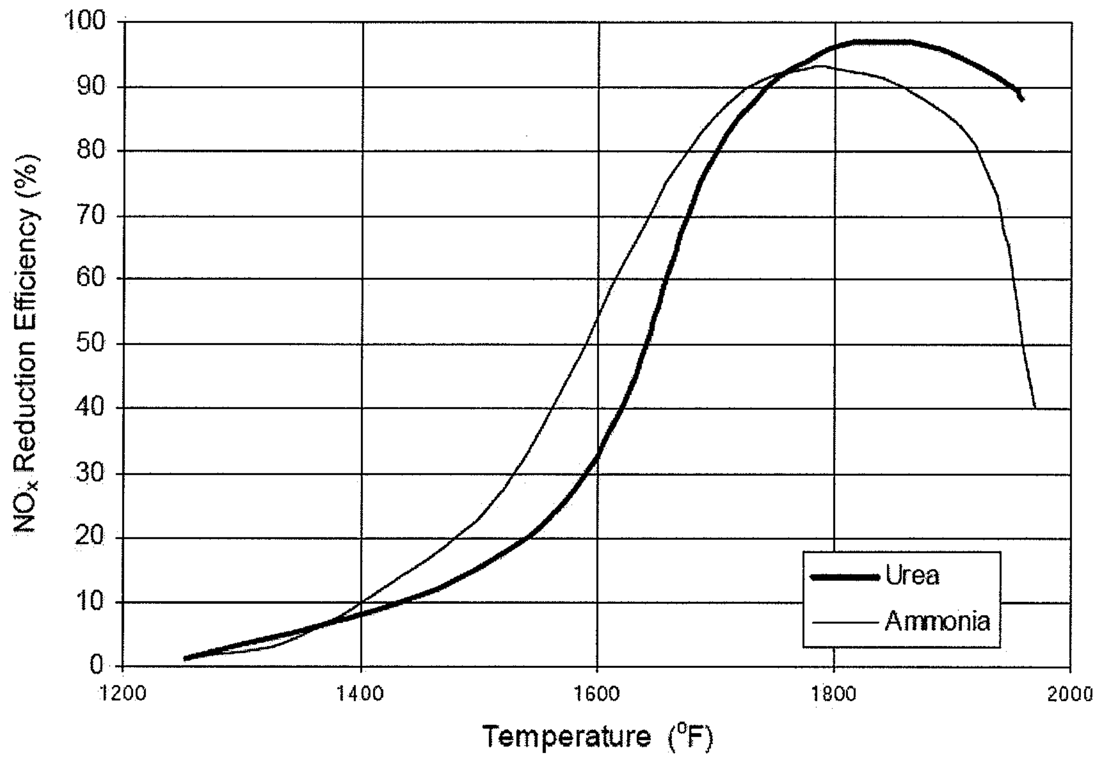

Figure 1.3: Effect of Temperature on NO_x Reduction

"Flue gas temperature within the boiler depends on the boiler design and operating conditions. These are generally set to meet steam generation requirements and are not always ideal for the SNCR process. Flue gas temperatures in the upper furnace through the convective pass may vary by ±150°C (300°F) from one boiler to the next [1]. In addition, fluctuations in the boiler load profile affect the temperature within the boiler. At lower load profiles, the temperature within the boiler is lower. Variations in the flue gas temperature make the design and operation of an SNCR system more difficult."

It is clear to the Department that startup and shutdown of the boiler will affect the SNCR system and perhaps the overfire system also (see p. 3-42 to p. 3-46 of Minnkota's BACT analysis). Minnkota has stated that startup has lasted up to

61 hours (2.5 days) for Unit 1 and 115 hours for Unit 2 (4.8 days). Including up to 4.8 days of start/shutdown emissions within a 30-day rolling average emission rate calculation will make compliance extremely difficult. In three recent PSD application reviews for power plants, the Department has found sufficient cause to provide alternative limits under BACT for periods of startup and shutdown. The State of Montana in the permit for the Highwood Generating Station, EPA Region 9 in the proposed permit for the Desert Rock Energy Center and the State of Nebraska in the Ag Soy Processing plant permit also included alternative limits for NO_x during startup and shutdown. Section 66 of the Consent Decree requires Minnkota to address in the BACT assessment specific NO_x emission limits during unit startups. Minnkota has evaluated the NO_x emission rates expected during startups. They evaluated the continuous emissions monitoring data and determined (and verified by the Department) the following maximum 24-hour average NO_x emission rates over the last five years:

Unit 1 - 0.980 lb/10^6 Btu
Unit 2 - 1.064 lb/10^6 Btu

Based on this data, Minnkota has indicated that the 30-day rolling average emission limit for Unit 1 should be adjusted by 0.041 lb/10^6 Btu per boiler startup and Unit 2's limit should be adjusted 0.102 lb/10^6 Btu per boiler startup. The Department believes adjustment of a 30-day rolling average emission rate for each boiler startup is not appropriate. Since most startups are relatively short (5 days or less), a 24-hour emission limit on a mass per unit of time basis is more appropriate and easier to enforce. It also provides more certainty of the environmental effects of emissions during startup or shutdown. For Unit 1, the Department proposes 2070.2 lb/hr (24-hour rolling average). This is equivalent to 0.83 lb/10^6 Btu/hr at a heat input of 2500 x 10^6 Btu/hr or approximately the same as the steady state pre-control emission rate of 0.85 lb/10^6 Btu. For Unit 2, a limit of

3995.6 lb/hr (24-hour rolling average) is proposed. This is equivalent to 0.83 $lb/10^6$ Btu at 4800 x 10^6 Btu hour. This is also approximately equivalent to the pre-control rate of 0.79 $lb/10^6$ Btu.

After considering all information, including the uncertainties associated with certain control alternatives, the NO_x removal rates of the alternatives, the costs, additional energy usage and environmental considerations, the Department proposes that BACT for both units at M.R. Young Station is represented by selective noncatalytic reduction (SNCR) operated in conjunction with advanced separated overfire air (ASOFA) and that BACT is the following emission limits:

Unit 1 - 0.36 $lb/10^6$ Btu on a 30-day rolling average basis except during periods of startup or shutdown. During startup or shutdown, NO_x emissions shall not exceed 2070.2 lb/hr on a 24-hour rolling average basis.

Unit 2 - 0.35 $lb/10^6$ Btu on a 30-day rolling average basis except during periods of startup or shutdown. During startup or shutdown, NO_x emissions shall not exceed 3995.6 lb/hr on a 24-hour rolling average basis.

For purposes of this BACT determination, startup is defined as:

The period of time from initial fuel combustion to the point in time when the measured heat input to the boiler on a 6-hour rolling average basis is greater than or equal to 2500 x 10^6 Btu/hr for Unit 1 and 4800 x 10^6 Btu/hr for Unit 2. For purposes of determining compliance, startup cannot exceed 61 hours for Unit 1 and 115 hours for Unit 2.

Shutdown is defined as the period of time beginning when the unit's generation is reduced in a continuous manner until combustion has ceased.

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Appendix A

Minnkota BACT Analysis
and
Additional Information

Appendix B

Evaluation of Particulate Matter Emission Rate